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PRESENTATION

Operator

Good day, everyone, and welcome to today's Ultra Petroleum Corp. First Quarter 2018 Earnings Conference Call. (Operator Instructions) Please note, this call is being recorded.

It's now my pleasure to turn your conference over to Ms. Sandi Kraemer.

Sandra D. Kraemer - *Ultra Petroleum Corp. - Director of IR & External Reporting*

Thanks, operator. Earlier this morning, we included in our news release results for the first quarter an update for 2018. In this call, we will provide additional information with our prepared remarks and reference to our updated investor presentation that was also posted earlier today on our website. I'd like to point out that many of the comments during this conference call are forward-looking statements that involve risks and uncertainties affecting outcomes, many of which are beyond our control and are discussed in more detail in the Risk Factors and Forward-Looking Statement section of our annual and quarterly filings with the SEC. Although we believe these expectations expressed are based on reasonable assumptions, they are not guarantees of future performance, and actual results or developments may differ materially.

Also this call may contain certain non-GAAP financial measures. Reconciliation and calculation schedules can be found on our website.

Thank all of you for joining us today. With me today is Brad Johnson, our Interim CEO; and Garland Shaw, our Chief Financial Officer.

Now I'll turn the call over to Brad.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Thanks, Sandi. Good morning, and welcome to Ultra Petroleum's First Quarter Conference Call. Last quarter, we set a new course for Ultra with emphasis on capital efficiency, discipline growth, visibility to cash flow and the pursuit of higher returns in order to drive long-term shareholder value. We have been busy implementing this transition and executing on our business plan.

Ultra is focused on maximizing the (inaudible) value of one of the largest oil and gas fields in the U.S., the Pinedale Anticline in Western Wyoming. The company's net daily production is 750 million cubic feet of gas and 6,000 barrels of oil per day. We are the largest operator on the field and controls 78,000 net acres. Historically, the company has developed a field with the vertical wells in the core. We have recently been focused on drilling horizontal wells starting on the East flank of the field. These wells have been generating superior returns to our vertical program of simultaneously adding recoverable resources by extending the boundary of the field. The horizontal well potential includes at least 700 net locations across 28,000 net acres outside the historical economic boundary of vertical well development.

Additionally, the company holds another 23,000 net acres beyond the 1,600 horizontal flank locations already identified. We believe this acreage is also a prospective for horizontal development.

Ultra is in the beginning stages of transforming the Pinedale Field from a vertical to a horizontal play, similar to what has taken place in other prolific basins. It is important to note that in addition to superior returns, our horizontal wells also produce significant oil rates with condensate yields much higher than the field average.

We believe the returns from horizontal wells in the Pinedale Field will highly economic on a return basis, at or even materially below current gas and basis pricing. However, as we accelerate the horizontal program, we want our shareholders to understand that, like any development play, there will be variability in our horizontal well results.

In the first quarter, production averaged 803 MMcfe per day, exceeding the midpoint of guidance. Consistent with our strategy for capital discipline, we reduced our operated rig count from 7 to 4 by early April. In doing so, we were deliberately maintaining a fleet of 4 rigs that are all equipped to drill 2-mile horizontal wells. Earlier this year, we set a goal to have 3 rigs drilling horizontal wells by year-end. Based on the encouraging initial well results, we challenged ourselves this quarter to ramp up the horizontal program at a faster pace. During March and April, we were successful on our effort to accelerate this program, and we currently have 3 of our 4 rigs drilling horizontal wells. A focused and determined effort across multiple teams and our organization has made this ramp-up occur sooner than what we had scheduled in our 2018 budget.

Since disclosing IP results of the Warbonnet 9-23-A-2H well in February, which had an IP of 54.5 MMcfe per day, including 873 barrels of oil, we had 2 additional wells that had posted IPs. The Warbonnet 9-23-A-3H had an IP just under 12 MMcfe per day, including 146 barrels of oil. This well targeted a lower interval within the Lower Lance A zone that is 160 feet below the previous 2 horizontal wells. The Warbonnet 8-25-A-1H well posted an IP of 28.5 MMcfe per day, including 441 barrels of oil. This well also landed in the Lower Lance A, returning to the same stratigraphic interval at the 2 wells with each had previously IP'd greater than 50 MMcfe per day.

The average cost of these 3 wells was $8.6 million and our average IP was 31.6 MMcfe per day, approximately 47% greater than our budget case for IPs. At this time, we have 5 wells that are in various stages of completion or early flowback, and we look forward to sharing results on these wells and more next quarter. Early execution and cost for performance is above expectations. Well performance is averaging above our budget case, with some expected variability to early time production rates. With each horizontal well drilled, we increase our learnings, improve our execution and reduce our cost.

We have significantly improved our cash flow visibility for both 2018 and '19, with ongoing increases to our hedge book. Nearly 200 Bcf of gas volumes are hedged for the remainder of 2018 with Henry Hub swaps for an average price of $2.89 per MMBtu. Of those Henry Hub swaps, 60% of that volume is paired with Northwest Rockies basis swaps averaging $0.69 less than Henry Hub.

We've also been hedging into the strengthening price environment for oil, adding nearly 2 million barrels of WTI hedges for full year 2018. Meaningful hedges have also been added into 2019 with recent focus on oil. We will continue to add additional gas hedges in a systematic manner in order to secure cash flows into 2019.

Last month, our borrowing base was reaffirmed at $1.4 billion. In addition, we announced -- as we announced last month, we pursued and received an amendment to our credit agreement that stepped up our net leverage ratio covenant to 4.5x through third quarter '19. This increased flexibility allows us to stay disciplined with our capital investments and to follow through with our plans to transition our drilling efforts to horizontal wells.

We have over $400 million of liquidity, and inside maturity is 4 years out. We feel confident, based upon our production forecast and increased hedging in '18 and '19, that our company will have no debt covenant issues.

At this time, I'm turning the call over to Garland to discuss first quarter financial results and to provide an update on our hedging program.

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

Thanks, Brad. As we pre-announced on April 19, the company produced an average of 803 million cubic feet equivalent per day or 72.3 Bcfe of total equivalent production in the first quarter.

Total cost of $2.28 per Mcfe, excluding stock compensation expense, were $0.05 below the midpoint of our expense guidance with lower lease operating expense being the primary reason. EBITDA cash cost of $1.05 per Mcfe were $0.01 lower than the midpoint of our guidance. Including our hedges, our realized revenue per Mcfe for the quarter was $3.10. Before hedges, our realized average gas price per MCF was $2.66, which equates to 89% of the average first-of-month Henry Hub price for the quarter. Our average realized oil price was $60.91 per barrel or 97% of the average WTI oil price for the first quarter. Our realized hedge gains for the quarter were $1.1 million.

Our resulting EBITDA for the quarter was a $148 million, which was in line, if not slightly better than our expectations.

The company has continued to significantly add to its hedged position in recent months as depicted on -- in the charts on Slide 6. Each chart provides the progression of our total hedged volumes as of May 8 relative to previous dates, as we continue to make efforts to protect our cash flows from a commodity price risk and provide cash flow visibility. The upper left-hand chart includes our 2018 gas hedging evolution, which has resulted in a total of 200 Bcf hedged, about an average price of $2.89 per MMBtu. 98% of these hedges are for the second through fourth quarters of this year in which we now have NYMEX loss in place for an average of just under 770 MMBtu per day.

As seen on the lower left chart, we have nearly doubled our basis hedge position since the end of February, as we have paired up almost 60% of our Henry Hub hedges with basis hedges. As of now, we have hedged a total of 118.7 Bcf of Northwest Rockies basis swaps at an average differential of $0.69 relative to the Henry Hub. Essentially, all of these hedges are for the second through fourth quarters of this year.

With the recent strength in oil prices, we have also added to our oil hedge book, to have now hedged nearly 2 million barrels for 2018 at an average price of $60.55 per barrel, as shown in the upper right-hand chart. Over 90% of these hedges are for the second through fourth quarters.

For the equivalent volumes that are fully hedged, we have provided a calculation of our realized price per Mcfe in the lower right-hand portion of this slide, where average NYMEX swaps and an average Henry Hub price of $2.89 per MMBtu, plus our average basis differential of $0.69, we realized a net price of $2.20 per MMBtu, which, after applying our 1.07 BTU factor, results in an average price per Mcf of $2.35. When we take our oil hedges into account and assume a 95% gas, 5% oil production split, we arrive at an equivalent price per Mcfe of $2.74. In the Appendix of this presentation deck, you will find more extensive details regarding our hedging activities for 2018 and 2019 volumes.

Now back to Brad.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Our capital plan continues to be driven by the following 3 objectives. First, the disciplined deployment of capital in pursuit of superior returns. Second, the increased visibility of cash flow, which, for 2018, has driven primarily by our efforts to significantly increase our hedge book. And third, the acceleration of our horizontal development, which provides strong economic returns, even during this challenging price environment for Henry Hub and Rockies basis pricing.

As I mentioned earlier, we are currently drilling horizontal wells with 3 of our 4 operator rigs, well ahead of our initial plans to accomplish this by year-end. We now plan to drill up to 30 horizontal wells in 2018. Because our capital spend rate per rig for horizontals is similar to the spin rate of our legacy vertical program, we continue to expect capital investments to be $400 million for the year. However, due to the improved well performance from our initial horizontal wells, we are increasing our full year production guidance by 5 Bcfe, announcing a new range of 285 Bcfe to 295 Bcfe for 2018. As we continue to see additional good results from our accelerated program with horizontal wells, we may consider further upward adjustments to production guidance.

We have extended the Utah asset sale process into the second quarter. Crude prices are up 10% since the first of the year, and we are focused on maximizing the value of the asset at current oil prices. This may include ultimately keeping the asset, especially if oil prices continue upward.

For the second quarter, our production guidance is at 780 MMcfe to 800 MMcfe per day. And the faster drop in vertical drilling than originally planned, near-term volumes declined slightly before production growth from horizontal wells kick in later this year.

Full year expense guidance is updated on the bottom right of Slide 7. Overall, expense guidance remains flat. We are guiding improved lease operating expenses and lower production taxes, but slightly higher net gathering fees, as we are projecting less profit-sharing credits from NGL processing.

On Slide 8, we are providing a look ahead for capital by quarter for the rest of 2018. In the first quarter, our capital spend totaled $131.5 million. This will be the highest quarterly CapEx low this year, as we ran 7 rigs in January and February, and then 5 rigs in March. We've dropped to 4 operator rigs in April and plan to hold that count for the remainder of the year. And because the capital spend rate per rig is currently the same for drilling verticals or horizontals, the capital forecast by quarter is proportional to rig count.

Over the next 3 quarters, we expect capital to range from $80 million to $100 million per quarter with full year CapEx remaining at $400 million.

For the balance of 2018, we will continue to track gas prices and adjust our drilling program accordingly, limit vertical well development to high-graded areas of the core, unless prices improve and continue to ramp up our horizontal activity, which, we believe, is still highly economic at current prices.

We have updated our vertical well performance chart to feature average initial rates for the last 5 quarters. In 2017, more vertical wells were drilled on the flank than in the core. In 2018, that proportion flips where more of the activity is focused in the core Pinedale.

Overall, due to the current price environment, the vertical program has dramatically reduced year-over-year. In the first quarter of 2018, we posted the highest average IP using the last 6 quarters where we brought online 42 operator vertical wells with an average IP of 7.7 MMcfe per day. Considering that our horizontal program does not materially reduce our vertical inventory, if pricing improves, we will revisit the ramping backup of the vertical program, which can produce solid returns in a more normalized gas price environment.

The 3 rigs currently drilling horizontal wells and a growing inventory of permits and approved drilling units, the company's ramp-up of horizontal activity is well ahead of our original schedule. We are now planning up to 30 horizontal wells this year with 7 horizontal wells already drilled in the first quarter. With this increase in activity, we are also accelerating the drilling of horizontal wells in the core of the field and also on the Western flank. We look forward to these results as we expect to continue to expand the resource and also to gain recognition for a larger inventory of horizontal locations.

We continue to maintain flexibility at our rig fleet and our standardized pat design that allows us to move rigs around as needed. We will continue to balance incremental earnings with cost efficiencies as we make decisions on where to drill future horizontal wells. Our original budget and our revised production guidance remains based on horizontal wells with IPs at average 21.5 MMcfe per day. Our internal target for these wells is to average 32.2 MMcfe per day. With cost decreasing, average well performance exceeding the budget case and the ramp-up occurring faster than planned, the horizontal program on Pinedale is on track to meet or exceed our expectations.

Slide 11 shows the well cost for Lower Lance horizontals through April. The last 3 wells shown here are under $9 million each. We are on a good trajectory toward our goal of $7.5 million per well by year-end. However, please note that we are maintaining $9 million cost per well for CapEx guidance.

We are consistently drilling these wells for less than $1 million per thousand feet of lateral, approaching our goal of $750,000 per thousand feet of lateral drilled.

We are extremely pleased with our early results of our horizontal program. We have been confident in our ability to execute and will remain so.

We have high-graded 8 target zones for horizontal laterals and a 6,000-foot thick pay column where we have historically completed 15 to 25 intervals in our vertical wells. This high grading is founded upon years of experience in Pinedale and a significant amount of data to support our efforts.

In 2018, our program is further prioritized to the Lower Lance intervals, representing half of the 1,600 gross locations identified to date. But even with this, the program is not immune to variability. So far, we have experienced variability in our IPs, which have ranged from 12 MMcfe to 55 MMcfe per day. In addition, although the data say it's limited by small number of horizontal wells, we are seeing a correlation between the ratio of net sand to gross lateral length and the initial productivity of our wells. This is not a surprising correlation and conforms with what one might expect. More net pay begets more production rate.

Another relationship one might expect is the positive correlation between well cost and the amount of net sand interval that is fracked. This is an important consideration when evaluating economic returns. Simply put, if we drill a well of lower net to gross, we can materially reduce the completion cost on that well by reducing the number of frac stages. That should allow for a lower IP horizontal well to still produce highly economic returns.

Slide 13 provides updated economics for horizontal wells. We have included a range of well cost from $7.5 million to $9 million. We have also included a range of net realized gas prices from $1.90 to $2.70 MMBtu. The net gas price represents Henry Hub minus Rockies basis, and the economics include the uplift we enjoy due to the high BTU content of our Pinedale gas and the oil revenue from the associated condensate production.

These results show strong returns even when Henry Hub minus Rockies basis produces gas prices below the $2 per MMBtu. Also the lower well cost that accompany wells with less sand can still deliver compelling returns (inaudible) the budget case for initial production rates.

On Slide 14, we show cumulative production versus time for a 4 Bcfe vertical well and also 2 type curves for horizontal wells, our budget case and our internal target case. The light blue curve shows the average of the 3 horizontal wells we have drilled on the Lower Lance A that have posted, at least, 30 days of production. This average curve is tracking well above our budget and target cases.

On the next slide, updated expense guidance is provided. This guidance accounts for the inclusion of Utah for the second quarter. And this guidance is similar to last quarter with small reductions to production taxes and lease operating expenses. We continue to project overall company unit cost to decrease throughout the year as volumes grow and also the assumption that Utah is excluded during the second half of the year.

To summarize, we've had a very successful first quarter in 2018. Our production guidance beat a meaningful beat on lease operating expenses and significant progress on the ramp-up of our horizontal well program. Thanks to the effort and focus across all of our teams. We now plan to drill up to 30 horizontal wells this year. And we feel confident in our ability to meet or exceed expectations with respect to both horizontal well performance and cost.

In addition, we have raised production guidance for the year by 5 Bcfe without an increase to CapEx.

At this time, we will open the line for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) We'll take our first question from Leo Mariani with National Alliance.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

I just wanted to dig in a little bit more detail on the latest 2 horizontal wells. Certainly, I guess, they had lower rates on some of the previous wells. And you guys indicated that these wells encountered less net sand, I guess, just over 5,000 feet, where some of the previous wells were more like 9,000 feet. Just trying to get a sense of why that was the case that these wells missed some other targets where maybe they were steered out of zone or maybe in this area of the field, maybe the sand disappeared for some period of time. What can you kind of tell us? Even though the actual lateral lengths of the wells were fairly similar to, I guess, the net sand, the hit was just a lot lower.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. Yes, this is Brad. Good question. The latter -- last 2 wells were both 2-mile wells, drilled in the Lower Lance A interval. And they did encounter less net sand along the lateral. The -- it's not an issue of drilling out of the zone. We target these wells. We pick our landing zone. And we stick with that stratigraphic interval as we drill out board from the Pinedale Anticline. And we do so with a lot of structural control based on our 3D seismic. The geologic nature of Pinedale does have variability and we certainty encountered that on these last 2 wells.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

Okay. So I guess, just essentially, where these particular wells were located, I guess, you're just saying that you didn't have as much sand along the lateral length. You felt like you steered it and then put it where you want it. But I guess, the sand just wasn't there as compared to a few of the previous laterals. Is that correct? I just want to make sure I understand.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

No, that's fair to say. In every well we drill, we learn. And as we drill these wells upfront to the edges of the field, really excited about the results we achieve. We're encountering sands down the hill. We're TD-ing wells, but still in sand, pressure and gas. So we find that very encouraging. On Slide 12, where we provided a table of wells, the Warbonnet 9-23-A-3H, which is the rightmost well featured on the table, on that particular well, we chose to land that lateral about 160 feet deeper to test a deeper interval within -- even within the Lower Lance A to identify its potential. And that's where we encountered, among these wells, the lowest net to gross. And when we encounter lower net to gross, we will reduce our stage count, as you can see on a table there, which certainty has a material impact to achieve a lower well cost. Those were -- as we drill these wells, we will design our completions to frac sand. So when we have lower net to gross outcomes, you should expect lower frac stages and also lower well cost as that data indicates on Slide 12.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

That's helpful color, for sure. And I guess, just additionally, you guys indicated you're going to start to move North and South along the Eastern flank and as well as test the Western flank. Can you just give us some thinking behind that? I guess, if you got 3D over this entire area, do you guys feel like it's pretty sufficiently mapped to know where you're going to be targeting these laterals. What can you kind of tell us about that? Sounds like material step-outs that are going to be happening during the course of 2018.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. As you know, there are thousands of wells in Pinedale. And so we have a significant amount of data, up and down the entire Anticline. And that data is also underpinned by a large 3D seismic volume that provides us a lot of structural certainty about a relatively simple geologic structure. When we set our plan out for 2018 a few months ago, that plan was to be -- to include 15 to 20 wells. And it did have focus in and around our most recent wells, and we'll continue to drill in that area. But as we've have the initial results, so far, to us, we're excited about those because, first, we are decreasing well cost. We're built to drill faster by having our permits and units formed and having been building a long runway for us to increase our activity. And with an increased activity, we're ready to spread out a bit. So we are going to move North and South and have started drilling wells on the core and heading to the West. And that expansion is a result of our ability to ramp up this program faster in 2018.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

Okay, that's helpful, for sure. And then, I guess, probably a tough question to answer but clearly, there's been significant dislocation in the price of Rockies gas versus where historical basis was the last handful of months. Do you guys have any type of sort of outlook for how long this may continue? Is this phenomena that could persist well into 2019? And kind of what can you sort of say about why you think this has come about in a meaningful way as it has? And do you see some relief down the road?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

We do see relief down the road, and we do expect Rockies basis to revert back toward historical trends. However, we're not going to make a prediction about exactly when that occurs and try to build our business around that. We've talked to a lot of smart people. We listened and read to a lot of commentary. And we acknowledge what is happening with respect to basis differential. And as it relates to the Rockies, with incremental gas from Permian moving West, some incremental gas coming down from Canada, all those issues are real. We acknowledge and agree with those observations. We do expect it to recover, but we're not going to try to predict that and build our business around it. What we are going to do is we're going to focus our investments on opportunities that are resilient, even to the Rockies basis conditions that are -- that we see today. And we are going to be continuing to hedge, both Hub and basis, in a manner, both systematically and opportunistically, that allows us to generate returns with our inventory of wells that we drill and to provide the cash flow we need to have the flexibility for our near-term plans.

Operator

We'll go next to Mike Scialla with Stifel.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Maybe just a follow-up to that last question. Brad, sounds like with about 45% of the basis hedged now, you're wanting to hedge more of that. Do you have a target in mind there that you'd like to get to? And is there any way to hedge basis with anything other than swaps?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So basis is certainly an important part of our hedge strategy. And when it comes to hedging basis, it is a less liquid market than, say, hedging Henry Hub. But we'll continue to do that in a systematic manner. Although we do not share details about that particular strategy and internal targets we have on that, but it is certainly going to continue to be an important part of our efforts as we go forward. There might have been a second part to that question. Did I...

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

No. I just wondered if there's any other instruments you could use other than swaps, but it sounds like you may be just limited to doing swaps.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

There are other instruments. And so far, all we have employed are swaps.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Okay. Wanted to also follow-up on the 2 newer wells that you reported rates on. Is there any predictability to the net to gross? Or is it just going to be a case of find out as you drill the well?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

There is some predictability in the sense that when it starts off with our selection of a landing zone. So when we use all the information and data from our vertical wells, field wide and then, specifically, in the area that we're drilling horizontals, we'll use a lot of information with respect to where there's production logs, open hole logs, well performance, et cetera. 3D seismic, we use all that information to help guide priorities about where to land wells. And we do have, although not thousands of wells, there are a handful of wells on the flank of Pinedale that help calibrate our seismic, and we also use that information to help develop our priorities about where to land wells. The effort is about in the 6,000-foot pay column of Pinedale, high-grading areas, we think, have the highest quality sands. And then as we drill off the flanks, focusing on landing zones that, we believe, as we drill down the hill, if you will, wells that we'll encounter, obviously, the most net to gross that we would like to achieve. But there will be -- there will continue to be variability. And when I look at the wells we share with Slide 12, certainly, the last well at 12 MMcfe a day was less than what we were hoping for. The Warbonnet 8-25-A-1H, very happy with that well. Although it's half the net -- almost half the net sand and 2/3 or 60% of the IP rate of first 2 wells, that's a very economic well. And we're really happy with the results of that one.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Okay. And heard you say you -- that you've started drilling on the West flank. Did I also hear you say you've started drilling horizontally in the core? Or did I mishear that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes. We have started that effort and -- in addition to core drilling West. So that's a part of -- it was not -- those wells have been on the board to drill, but it was not originally in our 2018 plan when we were speaking a few months ago about drilling 15 to 20 wells. But as we've been able to build permit inventory, drilling unit inventory and get the results that we had year-to-date that are as well above our budget case, the confidence to expand the program and that expansion does include laterals, North, South to the West and some laterals that would be considered landing in the core of Pinedale.

Operator

We'll take our next question from Brian Velie with Capital One.

Brian Taylor Velie - *Capital One Securities, Inc., Research Division - Senior Analyst of Oil and Gas Exploration and Production*

Most of them have been addressed, but I wondered if you could touch on the 5 wells you mentioned in the release that are in kind of various stages of completion. We know that 2 of them are in the table with the Lower Lance side. Can you first comment on those 2, whether they were targeting that slightly deeper interval of the Lower Lance A that you mentioned or how those compared to where those original 2 wells were drilled?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. Just for referring to our table, it's in our slide deck in the Appendix, Slide 28. And so the 8-25 A-2H and the Warbonnet

8-14 A-1H are both in the Lower Lance A, as indicated. One of those wells is drilled and landed in an interval that's about 160 feet below the 50 million a day wells. And another well is stratigraphic equivalent. So I described that a little bit on the pairs of wells on my remarks about this quarter we shared, one was stratigraphic equivalent and one was 160 feet below. That's the same for these next 2 pair that we have listed in the table. And then as a look forward, the additional activity will continue to be in the near-term second quarter going to be Lower Lance A focused. We are landing wells on multiple different intervals also within the Lower Lance A. And we're definitely encouraged by the performance and the execution of those well, so far. And we look forward to sharing performance results as they roll out.

Brian Taylor Velie - *Capital One Securities, Inc., Research Division - Senior Analyst of Oil and Gas Exploration and Production*

That's great. So the other 3 in that set of 5, we should expect that to be pretty similar. It sounds like everything's happening in the Lower Lance A for the near future.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

It sure look the second quarter, yes.

Operator

We'll take our next question from Marshall Carver with Heikkinen Energy.

Kyle Rhodes - *RBC Capital Markets, LLC, Research Division - Former Analyst*

The additional horizontal wells, will almost -- will most of those making the sales this year? I know you're drilling. When -- how many wells would you expect to put to sales in 2Q, 3Q, 4Q?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So the count has definitely increased. We're targeting now 25 to 30 for the year. It's still a ramp-up that will increase as we progress through the year. And the -- and I would expect 3 or 4 wells from an online standpoint to spill into 2019. And that's just with the expectation that at year-end, if I'm still continuing to run through rigs horizontal, which is the plan, then I would expect, if we finish up in December with 1, 2 or 3 wells, then those would spill into '19. So when we talk about 25 to 30 wells being drilled, you can -- I think it's fair to subtract that by 3 when you want to model out wells online.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Okay. And the working interest, on average, on those wells, what's the best guess?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes. We're still projecting an average working interest of 70% for 2018.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Okay. And the -- how many more vertical wells should actually go to sales? I know you're hardly drilled any vertical wells, but how many do you have in queue to go to sales?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

We have a handful more vertical wells that will go to sales. And -- but that pace will dramatically decrease. We have 48 total in the first quarter. 42 are operated. And that will decrease dramatically.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Okay. Do you have a ballpark number for vertical wells for the last 3 quarters of the year?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Less than 20 for the rest of the year.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Okay. And in terms of the horizontal, it seems like you were talking about that you would be doing sort of less exploration and more trying to drill wells with high rates and really aiming for productivity for the horizontal programs with the appraisal of the other intervals and drilling some horizontals on the core and testing other parts of the flank. Are you taking a little more risk with the additional wells this year? Or are you still aiming to get production as high you can from the horizontal wells if they're going to shift from the strategy there?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

No, not a shift with respect to. We're still -- our focus and our goal internally is to drill wells that make 30 million a day. That's our target case, and that continues to be our target case and still is our target case, even as we ramp up with the activity. With the results, so far, that we've had, on average, well above our budget case. And the execution success and trending with well cost going down, that gives us the confidence to expand the program and to drill more horizontals versus verticals. But our goal is still the same with respect to '18 program, and we are going to find out horizontal to deliver 30 million a day, on average. And we're going to encounter variability. We expect that when it's early and you have a sample set, that variability can be magnified a bit, but that's -- 30 million a day remains our target.

Operator

We'll take our next question from David Epstein with Cowen.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

Just following up on that last question. So just to clarify, landing a 160 feet deeper, that's not sort of -- maybe experimentation is okay, but that's not experimentation versus trying to land where the 50 million-plus ones were.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes, that effort was not about experimentation. As we've been -- again, it's early, and we learn new things with every well. And we had built our landing zones and targets in particularly with the Lower Lance A that has of 1,250 foot to 1,500 foot thick column. Early on, we have thoughts about frac heights being 300 feet. And so that's how we established our early assignment of zones within the Lower Lance. Some of the early data is indicating that frac heights are less than that, and so we wanted to see and test frac heights and frac length as part of our completion design. And so that was a big driver for us on the one well, the A-3H off of Warbonnet 9-23 PUD. Dropping that down 160 feet, if was -- it is and was drilled off the same PUD. That is 250 million a day wells. And so we wanted to test that. I would not call it an experimentation as much as just applying learnings from wells and trying to take learnings from one well and incorporate that in the next. And that's part of the early development process here that we want to try to maximize our learnings as we balance that with implementing this ramp-up.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

And you -- I think you said, yet, another one at that same level coming in Q2. Will you still be doing some of those and beyond the one that's already sort of in the queue?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

We'll continue to do landing zones that will target different areas within the Lower Lance A. And we've shared, the last couple of months, a schematic that was depicting 4 discrete zones on the Lower Lance A. But our guys have 10 zones that they want to test within that 1,500 foot column. And if the frac height proved out to be 150 feet high and 1,500 foot thick column in the Lower Lance A, in some places, that may very well play out. So those are the things that we want to learn early on, so that we can optimize the development and recovery of the opportunity.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

Okay. And for your 5 horizontals that are currently completing in flowback, any early signs you're getting from some of those? I see the frac stages were not quite as many -- well, I guess, it is similar to your -- the last 2 that you reported. One of them had a little bit lower lateral length. So anything you can comment on those 2 and maybe on what you're seeing in the other 3?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So we are seeing, as we drill these wells, the continued range of net to gross, certainly within an acceptable range to us to continue to ramp up this program. As you see lower frac stages, we are -- we frac sand. That's what we try to do. We don't have to frac the shale because we have sand. This is a sand play. And so we will adjust our fracs, frac counts(inaudible) downward in response, frankly, to the net to gross we encounter. And so the well cost performance continues to be very good. The execution continues to be very good. And we're excited about the results, so far. And we're excited about the upcoming wells and collectively, all that gives us the confidence to go faster.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

Finally, can I ask? Do you have any updated views on sort of maintenance CapEx as you guys move to an all horizontal program from whatever starting point you wanted to find in terms of production? And I'm guessing you've run something, like, on your budget case in terms of production and CapEx for a budget horizontal. Can you give us any help there? I think you've talked about a vertical-only maintenance in the past, but that (inaudible) changed.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. And I think we shared last quarter a maintenance capital from '17 to '18, which was the capital that we assigned to the vertical program, where, back in February, our vertical CapEx program was $270 million for the year. And that program was set to keep volumes flat in Wyoming year-over-year. Now as we allocate more capital to horizontal wells, which have better returns and, certainly, a higher deliverability for each one of those wells, that should deliver (inaudible) production at lower CapEx over time. So that's -- we would expect that maintenance capital to potentially decrease. I don't have an updated projection, though, say, from now into next year. We'll get that number more refined as we move forward to the year. The other aspect to that would be the horizontal program with the better returns, greater deliverability. A third -- or half of the SMB of the vertical program, all those things collectively give us the opportunity for horizontal program to, a, deliver [high] production with less capital and, therefore, less maintenance CapEx or more growth at the same level of CapEx. So those are -- considered those as both positive. they have -- and we'll continue to allocate capital to more horizontals as we move forward.

Operator

We'll go next to Stephen Koenig with Guggenheim Partners.

Stephen Koenig

Most of my questions have been answered. I guess, I just want to turn a little bit quickly to the one rig that's running, I guess, with vertical wells right now and understand that part of this is that the horizontal program is just showing better economics, and so there's some switch there. But I guess, kind of absent of that, I mean, what does your inventory look like if vertical wells that are economic given to kind of where gas and where basis is right now?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. And I might refer everyone to Slide 9 in our slide deck, where we show an update of our vertical well performance. And certainty, we're showing -- we've provided here the -- an update on our wells that we brought online in the first quarter of 2018 where we averaged 7.7 MMcfe per day. So tracking right on or slightly above our book 4 BCF type curve and posting results the best we've had in 6 quarters, as our vertical program has been focused in the core of the field. So the vertical wells are -- these types of wells are certainly economic at current gas prices. They're not widely economic, but they are economic. But they just don't compete with horizontals at this point in time. So that's why we're moving more capital to the horizontal program. Having said that, we have a significant number of vertical wells that are economic at current prices.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

No, that makes sense. I guess, I was just wondering the thought behind -- obviously, the horizontal program ramping that and seeing where the capital spend goes there, but then essentially netting that off and drilling fewer wells of verticals. It was -- I guess, I'm focused on the decision to kind of keep the capital budget the same. Is that just because you'd rather wait and save some of those vertical wells for a rainy or, I guess, a sunny day when gas prices are better? Or is that just something you were just focused on maintaining your capital budget?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Well, capital discipline is a pillar to our strategy. And we're not just going to drill wells to grow. We're going to do so on a prudent manner. And for 2018, we want to spend within cash flow, and that is our objective. And under current gas price environment, spending within cash flow calls for a budget that's right around $400 million. And in doing so, the opportunity to shift capital through horizontal wells is just, for us, the obvious thing to do given the superior (inaudible).

Operator

We'll go next to Kevin Kuzio with First Eagle.

Kevin M. Kuzio - *First Eagle Investment Management, LLC - Senior Credit Analyst and Research Analyst*

I have a question about your reserves. You note that the horizontal program has not reflected in your reserves yet. I just wonder if we should be looking forward to an interim reserve update sometime during the year? Or should -- is that something that's going to come together at the end of the year?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

I would expect us to provide horizontal reserves at the end of the year, as far as PUD locations, et cetera.

Kevin M. Kuzio - *First Eagle Investment Management, LLC - Senior Credit Analyst and Research Analyst*

Okay. I had another question about Slide 12. You -- later back in the Appendix, there was a note that says that the IRR opportunity under the horizontal program could potentially exceed 100%. And I know you don't have a lot of wells here yet, But -- in that Slide 12, are the IRRs widely ranging there? Or can you give any sense of something that could help balance the changes in CapEx that you demonstrated there versus the production levels?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So for the horizontal well economics, we do have an updated slide on Slide 13. And we've done 2 things, really, with this update on Slide 13. First, we wanted to provide a range of type scenarios that take us even below where we are today. And then the other thing we wanted to look at -- or provide was the CapEx sensitivity. And that CapEx sensitivity is important to take into account, particularly as we have the variability of net to gross on our laterals and where a significant amount of the capital in a well is invested in the completion. And if we do have lower net to grow or lower net sand across or along the lateral, we're going to frac less and we have less stages and, therefore, less completion cost and less overall well cost. So what we're trying to demonstrate here is that as we encounter geology that delivers less net to gross, those outcomes are certainly going to have, we believe, lower production, but should have much lower well costs. And we wanted to make sure that was conveyed in this table that wells that even fall below our budget IP, for example, still deliver strong returns, even when stressed down at prices that are lower than they are today.

Operator

We'll go next to Vivek Pal with Seaport.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

Just any update on your asset sales. You had mentioned that you're looking to sell the Uinta Basin assets. Any update on that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes. I mean, we had extended that sales process into the second quarter, and we are reevaluating our options. We received meaningful interest in the asset. But year-to-date, oil prices have moved up significantly since we've been marketing the asset. So ultimately, we want to make sure we maximize the value of this asset. Right now, we don't want to allocate any capital to Utah. The lease operating expenses is as lowest that it's ever been. And our base production is outperforming forecast. So we are reevaluating that process and looking at our options. And as a result, in our guidance, we have extended the Utah asset into second quarter with respect to volumes and expense. Going forward, any more news on that, we will certainly share that at the appropriate time.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

And in terms of your cash burn for this year, you're saying $400 million CapEx. It seems like you should be modestly cash flow positive, right? It seems like you've hedged almost everything in terms of Henry Hub, but have some exposure on the basis side of over 55%. What are your thoughts on that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

No, I agree.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

You should be cash flow neutral.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

To modestly positive.

Operator

Next, we'll go to Sean Sneeden with Guggenheim.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Brad, I guess, on the 83 well, was that an infill well on 0.25 mile spacing? Or what was the spacing on that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes. The 83H well was drilled between the A1 and A2 wells. And so it was an infill, if you will, and was also drilled 160 feet below.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. So 0.25 mile spacing between laterals.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes, that's correct.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. Great. And I guess, when you were completing that well, do you see any interference between parent and child at all? Or anything that -- of note, I guess, on the completion would be helpful.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. We did not observe any production impact on the offset wells, if that's what you mean by interference.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay, that's helpful. And then, I guess, on your Slide 17, I think you show some of the average on Lower Lance A wells on a Bcf basis. Just out of curiosity, how does the GOR progress over time there, presuming that there's a bigger upfront kind of oil content that's been there (inaudible) over time? But any kind of color around that will be helpful.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. And I'll flip that over and talk about condensate yield, which is obviously just oil over gas. The wells do come on at 2 to 3x yield higher than our field average. And we do see the yield fall off a little bit. So wells that are, for example, having early yields of 20 barrels a million, we have seen them fall down and stabilize at around 15 barrels a million, for example. So we do see some early time, but then it stabilizes and holds flat.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. I mean, that holds flat at the, like, 11, but you kind of put that in your guidance.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes. We're just using 11 on that because that's an average of vertical wells on the East flank. Frankly, recently, we've seen that average because that's what we're using. We're exceeding that yield in our horizontal wells not only all the time, but even on a sustained basis. So that yield assumption falls on the conservative side.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. That's very helpful. And then, I guess, Garland, it's certainly good to see the borrowing base got reaffirmed. Can you just help us on understanding what differential on Rockies the banks were assuming? Was it kind of generally based around the strip during April?

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

That's a good question. We get a price deck from the banks that has Henry Hub forecast and a WTI forecast. They don't give us a Rockies forecast. So I've seen they're running their own forecast. And we're not really privy to what that is.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. But at least, I guess, the Henry Hub forecast sort of give you around the strip of the time.

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

That's right.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. And then maybe just kind of one last big picture question. I guess, just on the kind of California Solar announcing yesterday, how does that, if at all, factor into your decision to hedge further on basis in '19 and beyond?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Well, certainly, California is where, historically, our gas has been sold out of the Rockies, and we expect that to continue to do so. So we do keep a close eye on the market in California and all the dynamics there. I wouldn't say that one particular event or one particular news story or observation report is going to trigger a change or a reaction here around our hedging strategy. We're going to take into account all sorts of factors, observations, news reports, et cetera. But we're going to hedge in a systematic and opportunistic manner.

Operator

Our next question is from Asif Chaudhry with Waddell & Reed.

Asif Chaudhry

My question was around the sort of California Solar (inaudible), but I don't have anything else.

Operator

And we can go next to Leo Mariani with National Alliance.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

Just to -- a couple of follow-ups here. So on the headquarter's move, will there be some shut down cost you guys incur on that later this year? And would you expect that to save and sort of recurring G&A post that? And what do you think the savings would be?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Well, first, regarding the headquarters, certainly, our decision like that is not something we take lightly. In our Houston office, it's got 14 very talented employees that have made significant contributions to this company. There are cost savings related to the office closure. But really, the driver was not about that. It was about consolidating 2 offices into 1 in order to be more efficient and focused on our go-forward plan.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

Okay. And then just jumping back over to Uinta. You certainly mentioned that base production was kind of performing better than planned. Could you give us a sense of what that was here on the first quarter? What was the Uinta production maybe in terms of oil in total?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

On a quarterly basis, the Utah production is about 1 Bcfe. So flipping that back over on an equivalent oil basis, of course, divided by 6.

Leo Paul Mariani - *National Alliance Securities, LLC, Research Division - Research Analyst*

Okay. And then, I guess, just with respect to Rockies gas prices. Obviously, a lot of discussion about prices being weaker of late, of course. And you guys showed some of your sensitized economics in the slide deck, as well. I mean, is there a particular price where, if we got to or say, Rockies gas was thought at $50 later this year, would you all consider paring back the capital program?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

We -- certainly, the things we've been doing over the last few months is to make sure we have maximum flexibility with respect to our capital program. So that flexibility means that if prices do continue to degrade, we would have the flexibility, and we would scale back capital. That's what we did for 2018 relative to 2017. And so we have that flexibility. That's something that's very important to us, that we maintain that flexibility. And so if prices do degrade further, we do have that flexibility to scale back. And alternatively, if prices improve and strengthen, either Henry Hub and/or basis, we'll be poised to increase capital if it makes sense to do so.

Operator

It appears we have no further questions. I'll return the floor to Brad Johnson for closing remarks.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

I wish to thank everybody for joining us this morning on our call. And if you have further questions, please follow up with Sandi Kraemer. Thank you, and goodbye.

Operator

This will conclude today's program. Thanks for your participation. You may now disconnect. Have a great day.
